

July 1, 2009

Matthew Crosby
Policy and Planning Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

RE: Comments from EPRI on California Public Utilities Commission Staff's White Paper, *Light-Duty Vehicle Electrification in California: Potential Barriers and Opportunities*, May 22, 2009

Dear Matthew:

The Electric Power Research Institute (EPRI) commends the California Public Utilities Commission for addressing the opportunities and challenges of light duty vehicle electrification in California at this time. Auto manufacturers are bringing electrified vehicles to market starting in 2010 and we are pleased that California is planning ahead.

EPRI's comments are focused on technical topics. Marcus Alexander, Senior Project Manager, led the development of the comments and incorporated input from the EPRI team, including Mark Duvall, Director, and Sunil Chhaya, Senior Project Manager.

We received input from Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and other members of the California Electric Transportation Coalition. We also understand that utilities are filing individual comments focusing on policy issues.

We provide input on the following major topics, as well as on several additional topics:

- Water use for electricity generation
- Charging rate assumptions
- Potential emissions impacts
- Battery charging and use
- Lifecycle costs

Thank you for the opportunity to comment on the Light Duty Vehicle Electrification white paper, and we look forward to continuing to work with the California Public Utilities Commission as California electrifies its transportation.

Sincerely,



Ellen M. Petrill
Director, Public/Private Partnerships

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3420 Hillview Avenue, Palo Alto, CA 94304-1395 USA • 650.855.2000 • Customer Service 800.313.3774 • www.epri.com

Water use for electricity generation

Water is used in many processes during electricity generation, but its primary use is in thermoelectric (steam-driven) generation plants for cooling of spent steam upon exiting the generating turbine¹. These plants can use a variety of fuels to generate steam, including coal, natural gas, oil, nuclear or geothermal resources; likewise there are a variety of cooling technologies available to condense the spent steam.

There has been recent discussion on the potential impact that transitioning transportation fuels from petroleum fuels to electricity may have on increasing the stress on our water resources. These concerns should not be neglected, but they should be analyzed with an understanding of how future energy choices impact water resources. Looking at average rates of water withdrawals and water consumption is one methodology, but another is to look at the existing trends and the existing actions that different industries are taking to address their water footprint.

Section 2B of the CPUC whitepaper makes some broad conclusions about the water impacts of electric transportation. The cooling requirements for electricity are stated to range from 7.4-20 gal/kWh for combined cycle natural gas generation, 21-50 gal/kWh for coal and oil facilities, and 25-60 gal/kWh for nuclear power plants. However, these values do not reflect current trends in thermoelectric cooling in the US and certainly do not reflect the status of water use for electricity generation in California. We note the following:

1. The values stated in the CPUC white paper are representative of open-cycle cooling technologies. These are considered an upper-limit as more power plants in the U.S. move to closed-cycle or other low-water intensive technologies, such as air-cooled condensers.
2. Aside from the notable use of saline water in open cycle cooling in nuclear facilities in California, thermoelectric generation plants in California use predominantly closed-cycle or other low-water-intensive technologies such as air cooled condensers.
3. The two nuclear base load power units in California are both cooled with seawater, i.e., the most freshwater conserving option.
4. Out of state power is provided primarily from fossil units using cooling towers (closed-cycle cooling) and from hydropower resources in the Pacific NW.

¹ This commentary does not take into water requirements for hydroelectric power; water use by hydroelectric facilities counts all water flowing through turbines, a very different metric than other water requirements for generation. However, hydropower is not a marginal electric generation resource and would not be attributable to electric transportation demand.

5. Aside from nuclear power and power imports, natural gas combined cycle power provide the next largest generation pool for California. These plants generate 2/3 of their power from gas turbines (the Brayton cycle) and one third from the steam-driven turbines (the Rankine cycle). These units use low-water-intensive technologies such dry cooling and cooling towers on effluent, with a few using cooling towers on freshwater.
6. The values in the CPUC white paper are taken from only one source and do not reflect marginal withdrawal and consumption trends in California and the United States. In fact, the marginal withdrawal intensity in the U.S from 1990 to 2000 has been hovering around 0 gal/kWh. Additional information from other resources should be evaluated in order to obtain a clearer picture of current trends in water use for electricity generation.
7. Water withdrawal is only one aspect of water use in electricity. Another metric – a metric of particular concern in regions with water limitations – is water consumption, i.e. water that is consumed and not returned to the source. Consumptive use is a better indicator of stress to water availability than water withdrawal. A recent NREL report (Table 2 in Appendix A and references in Appendix B) calculates that thermoelectric cooling requirements in California result in an average of 0.05gal/kWh consumptive freshwater use, one-tenth of the national average.

To better illustrate the impacts of these observations of the current trends and marginal intensities of water use in the electric industry, we will calculate the water intensity per electric mile driven in California. Although the future electric resources in California will have to satisfy California's Renewable Portfolio Standards, we will make the conservative assumption that all the marginal generation to power vehicles is from natural gas. In addition, we will use the current average thermoelectric freshwater consumption rate of 0.05 gal/kWh although marginal rates will be lower due to water restrictions and the continued use of low-water-intensive cooling technologies. With upstream water requirements, this leads to a water consumption intensity of 0.13 gal/kWh. Assuming 0.24 kWh/mi (4.5 mi/kWh at the vehicle level, plus losses due transmission and distribution), **a conservative estimate** of the water intensity of electricity in California is 0.03 gal/mi. This compares quite favorably to the ranges and is less water-intensive than the values given for other transportation fuels in the manuscripts cited by CPUC white paper (Table 1).

Table 1: Water consumption for different transportation fuels

Fuel	Water Consumption (gal/mi)
California Electricity	<0.03
Gasoline	0.07 – 0.14
California Gasoline Blend (E5)	0.13 – 3.2
E10	0.19 – 6.3
E85	1.3 – 62
Diesel	0.05 – 0.11
Tar Sands	0.15 – 0.37
Oil Shale	0.20 – 0.46

* Ethanol values assume corn-based ethanol

In reviewing the literature, the concerns over the water intensity of electricity for transportation purposes seem founded on one data source, do not reflect the current trends and marginal intensities for water use in the electric industry in the U.S., and are far removed from the situation in California. We provide a conservative estimate for electricity in California; indeed, a marginal water-intensity analysis would be required to provide a more rigorous estimate of the water intensity of California and would likely lead to even lower values.

Appendix A provides additional information on the use of water resources for electric production. Appendix B provides a list of additional available resources (manuscripts, reports, presentations) that are available to evaluate the impact of electricity on water resources.

Worst case charging rates

In analyzing the potential generation and transmission impacts of electric vehicle charging a 'worst case' scenario will be needed to estimate the potential negative effects; however, it is important for this worst case to be plausible. There are uncertainties in how vehicles will be charged, but these uncertainties can be reasonably bounded at the aggregate level.

It should be noted that at the distribution level this aggregation would not be achieved and local concentrations of vehicles can cause negative impacts which should be analyzed separately. For example, Figure 1 shows the change in life expectancy for a 25kVA transformer as the number of PHEVs per utility customer changes. This type of transformer is used at the neighborhood level (about 5 customers), and each utility 'customer' represents a household. It is possible that in some neighborhoods 2 or 3 PHEVs per household could be present even in the near-term market, which would shorten the transformer life to 1/10th of its expected value if high rate charging was

used. This expense is currently not accounted for in distribution maintenance budgets. EPRI is performing an investigation of these distribution system impacts in order to better estimate potential costs.²

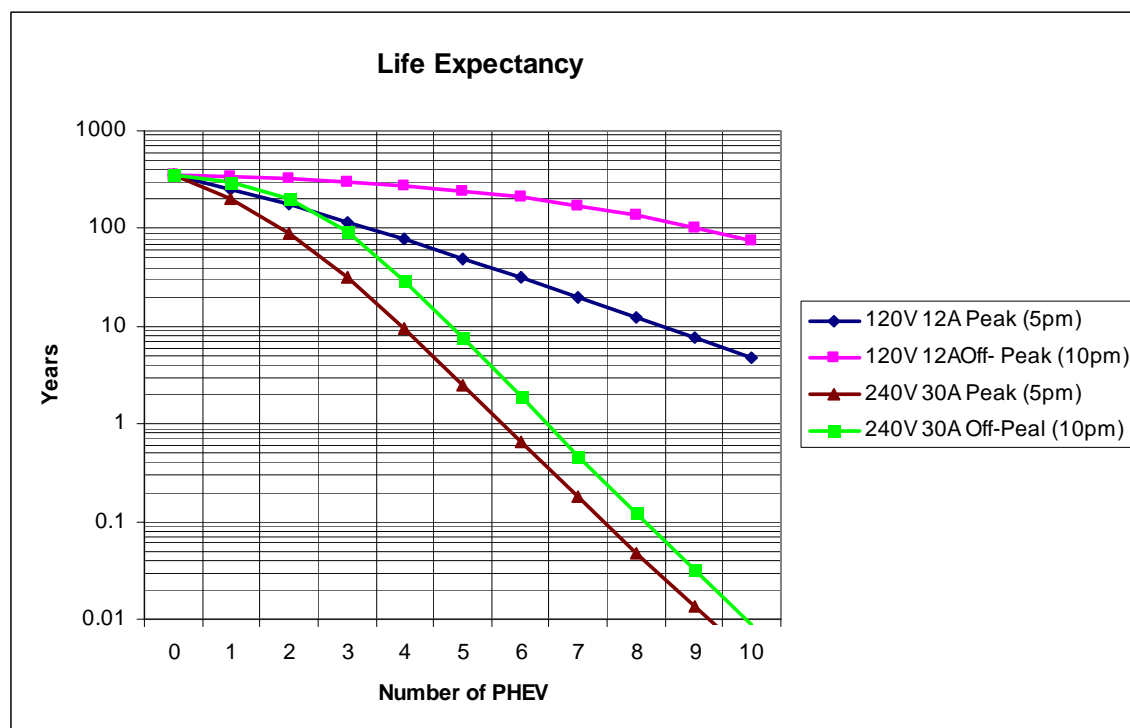


Figure 1: Life expectancy for a 25kVA transformer under various charging scenarios

At the transmission and generation level, charging patterns should correlate more closely with statistical driving patterns. EPRI has done analysis of data in the National Personal Transportation Survey (NPTS) in conjunction with Argonne National Labs to try better estimate aggregate impacts, although this work has not been published yet.³ It should be noted, though, that the NPTS database reflects all car users and a mature market. It is likely that new car buyers, commuters, and other early adopter segments could have different driving patterns and could cause very different generation and transmission level impacts in the early years.

² The paper "Evaluation of PEV Loading Characteristics on Hydro-Quebec's Distribution System Operations" presented at the Electric Vehicle Symposium – 24 provides an initial example of the work EPRI is performing, in this case for the Hydro-Quebec distribution system. Unfortunately analysis at this level is highly system-dependent, so these results are not applicable to California utilities and a separate analysis must be performed.

³ Vyas, A, Wang, M., Santini, D., and Elgowainy, A., Analysis of the 2001 National Household Transportation Survey in support of the PHEV project to evaluate impacts on electricity generation and GHG emissions, unpublished information, 2009.

In the case of uncontrolled charging it is likely that vehicle charging could create a large load coincident with the peak. However, vehicles will not all be connected at the exact same time. Figure 2 shows the distribution of home arrival times for an average American driver. Even during the peak hour of 5-6 PM, only about 12% of drivers arrive home during the hour.

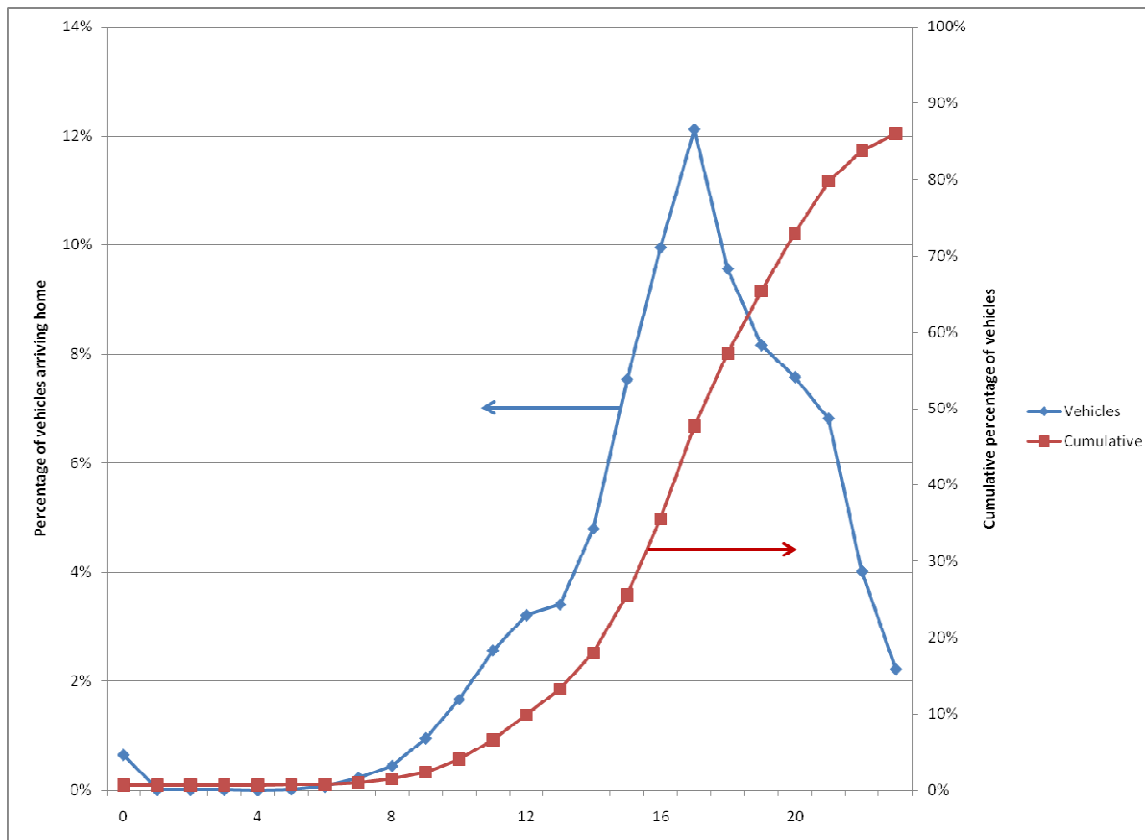


Figure 2: Home arrival time distribution

Further analysis of this data by EPRI demonstrates that even without smart charging the load of vehicle charging is well distributed. For example, Figure 3 shows a plausible high case, which assumes that all vehicles are electric vehicles with 7.8 kW chargers which begin charging at full power immediately upon arriving at home. Since home arrival is coincident with other activities the load occurs on-peak, but vehicle charging has a maximum of about 0.9 kW per vehicle, and is relatively evenly distributed over about 7 hours. Other vehicle mixes which include PHEVs or lower power chargers will decrease the vehicle charging peak and shift it later. However, early customers may have a different driving distribution from the averages measured by the NPTS, and other factors may concentrate the load within a narrower timeframe.

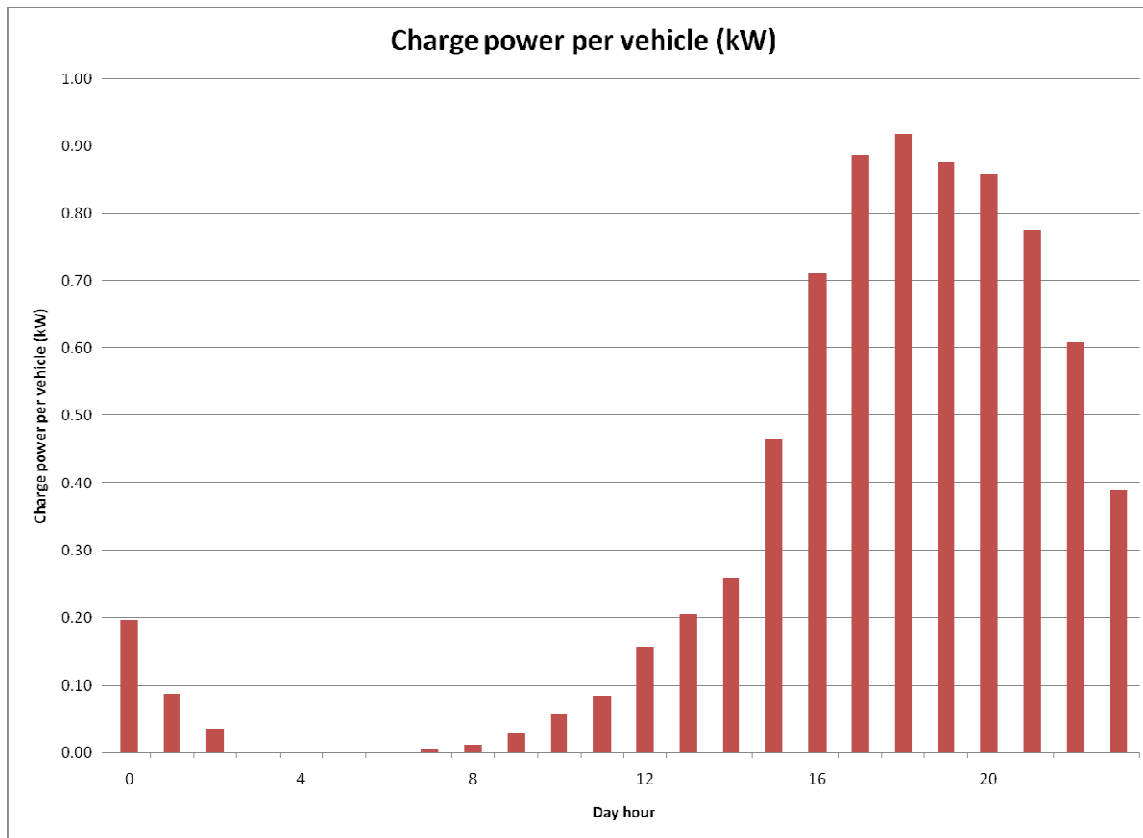


Figure 3: Uncontrolled electric vehicle charging

Significant problems may also be caused by incorrect control. Figure 2 also shows the cumulative percentage of vehicles which have arrived home at a given time, which indicates the potential for negative impacts. For instance if vehicles were controlled with the algorithm “wait until 8PM and then turn on,” with the assumption that this would move the load off of the peak, the load from charging could quickly ramp from 0 kW per vehicle to an average of 5.6 kW per vehicle (7.8 kW times 72% vehicles available to charge). Even though this load would be at the end of the system peak, this would present a very difficult control problem for utilities, even with a relatively small number of vehicles. Due to the variation in load patterns and availability of grid resources it would be very difficult for a non-utility entity to correctly distribute load. The 6x difference between the 0.9kW ‘uncontrolled’ case and the 5.6kW ‘incorrectly controlled’ case illustrates the importance of achieving some level of communication and control. (It should be noted that lower power chargers decrease the absolute numbers for each vehicle, but have similarly high ratios between the uncontrolled and incorrectly controlled case.)

EPRI suggests revisiting the following sections based on this alternate ‘worst case’ assumption:

Page 34: “in an extreme, ‘worst case’ uncontrolled scenario ... 5,400 MW are needed ... if the vehicles charge at 120 Volt (V) outlets, or 19,800 MW for 220 V outlets.” This type of synchronization is highly unlikely, and is not used when provisioning systems for other loads like air conditioners, lights, and TVs, each of which would overwhelm the electricity system if all assets were used simultaneously. Based on the scenario above the required capacity for 3 million vehicles would be about 2,750 MW; less would be required for 120 V charging.

Page 34: “The ORNL study finds that if 25% of the U.S. vehicle fleet is replaced with PHEVs, and these vehicles all charge at 6pm, up to 160 new power plants may be needed across the nation.” This result is highly implausible and has not been reproduced in other studies of future generation needs. It should not be used as a reference point for guiding future analysis.

Potential emissions impacts

Page 21: Two studies are referenced in regards to the potential for increases in emissions from electrification. The ORNL study does not use a full production simulation, so this methodology is unsuitable for modeling future electricity sector impacts. However, it should be noted that the results still appear to be positive in all scenarios for California. The McKinsey paper does not contain enough information to evaluate the methodology, but the results appear to be specific to the generation mix in China, which is significantly different from California. This is a subject which deserves further study, but should be done with a suitable methodology for California’s grid.

Battery charging and use

The interface between vehicles and the grid will be a key focal point for future regulation. This section addresses various aspects of this interface.

Page 33: “According to experts, the value of [ancillary] services accounts for 5-10% of electric service cost.” The California Independent System Operator prepares an annual report on market operation. Table 2.5 in the 2008 report shows the historical percentage of ancillary services costs as a portion of total wholesale electricity costs in the California ISO (partial excerpt)⁴:

⁴ California ISO. Market Issues & Performance; 2007 Annual Report. (2008)
<http://www.caiso.com/1f9c/1f9c8b49e9f0.pdf>

Year	Ancillary services prices as a portion of wholesale cost
2007	1.3%
2006	2.0%
2005	1.7%
2004	1.4%
2003	1.7%
2002	1.5%
2001	5.0%
2000	6.1%
1999	5.2%
1998 (9 months)	10.0%

After market restructuring and the resulting price fluctuations, ancillary services have consistently been between 1.5% and 2.0% of total wholesale costs. The value of reducing peak load is separate from this since capacity to meet expected loads is purchased on the energy market and not the ancillary services market. Ancillary services would be a smaller proportion of the consumer cost (the potential meaning of ‘electric service cost’ in the quote above), which includes delivery and other costs.

Page 37: “Obviously, PEVs require longer refueling times relative to gasoline, which requires consumer behavior change.” PHEVs have the capability of filling up at a normal refueling station, so no behavior change is required although it would have a benefit to the consumer. Home recharging of PHEVs and EVs is generally seen as a benefit in consumer surveys since refueling at a gas station is seen as a task rather than a benefit. The range limitation of EVs often leads to ‘range anxiety,’ which can be dealt with through behavior changes, traditional 240 V public charging, various types of fast charging, battery exchange, or purchasing a PHEV or limited-function EV instead of a full-function EV.

Page 41: “Level 2 is preferred method to Level 1 due to increased power and a higher level of safety required by the National Electric Code (NEC).” Both Level 1 and Level 2 charging are covered by the NEC and other applicable electrical safety standards and should both be considered safe. Level 2 may be preferred to the consumer due to the increase in available power, but this will be situation-dependant. However, the Commission may want to consider the distribution impacts of level 2 (3.3 kW to 19 kW while charging) on utility ratepayers, as these can be significantly more than the level 1 impacts.

Page 42: “There are five times as many cars as garages in the U.S., indicating a clear demand for on-street charging stations.” This statement requires more rigorous analysis before it should be used, and is not logically consistent: cars not parked in

garages may not be parked on the street. A better metric would be the proportion of cars which do not have permanently dedicated parking spaces. In addition, there are several studies on this topic which give quite different answers.

Lifecycle costs

A lifecycle cost analysis was performed by CPUC and discussed on page 28. This type of analysis is difficult and depends critically on the assumptions and methodology. The data used by CPUC differs significantly from the data used by EPRI in similar analyses. In addition, there are many other analyses and conference papers that examine this issue which have arrived at significantly different results.⁵ A full cost analysis is beyond the scope of these comments, but a simple, illustrative analysis is presented below using many of the CPUC assumptions on page 28 with some different assumptions and a different methodology which is more representative of those used by EPRI.

This analysis assumes the use of an electrically-intensive PHEV 40, which is expected to have near-term incremental costs similar to those selected by CPUC. This system is more expensive than other PHEV options, but provides an interesting illustrative case for how incremental costs can be balanced with operating cost savings. The costs for the first generation of this technology will be quite high, so it is unlikely that the consumer will fully recoup upfront costs. However, experience with the first generation technology will allow for significant cost savings in the second generation of vehicles, and further cost savings can be expected in subsequent generations, although at a lower rate of improvement. A full incremental cost model was not developed for this analysis, but it is assumed costs can be reduced by 50% in the second generation, and 40% in the third generation.

Costing methodology – Analyses of this type are typically done using a ‘net present value’ methodology. This methodology accounts for the fact that future savings are less valuable than savings in the present, so they should be ‘discounted.’ A full description of this methodology is beyond the scope of this paper, but for reference a discount rate of 8% is used below.

Gasoline cost – Gasoline costs are the most volatile component of this type of lifecycle cost analysis, and also one of the components with the highest sensitivity. In past analyses it has been found that the best way to handle these costs is to make them explicitly variable and present results over a relatively large range in order to let the reader reach their own conclusions about appropriate cost values. This is partially done in the CPUC analysis, and will be done below.

⁵ Tayler, D, Duvall, M. Life Cycle Cost Analysis of Plug-in HEVs, Power Assist HEVs and Conventional Vehicles. EVS-22 (2006).

Electricity cost – Electricity costs are relatively stable, but there can be widely varying costs for different types of consumers and for different types of activities in order to implement incentives and handle varying delivery costs. Overall cost analyses are usually relatively insensitive to electricity costs, though, so any reasonable figure can be used. This analysis uses an electricity cost of \$0.10/kWh, which is similar to rates currently available for off-peak charging from California utilities.

Vehicle efficiency – There are various options available for representative reference vehicles and representative PHEVs. In this analysis, the reference vehicle was chosen to be the Chevrolet Malibu Hybrid, which achieves an average fuel economy of 29 miles per gallon (MPG), and the PHEV was chosen to be the Chevrolet Volt. Efficiency data for the production Volt is not yet available, but initial announcements indicate a gasoline fuel economy of 50 MPG and an electric economy of 4.5 miles per AC kWh (5 miles per DC kWh with a 90% efficient charger).

Annual mileage and utility factor – According to the EMFAC database maintained by the California Air Resources Board, the average California personal vehicle is driven around 12,500 miles per year. However, the annual vehicle miles traveled (VMT) changes significantly over the vehicles life. Figure 4 shows the distribution of VMT verses vehicle age derived from the EMFAC data which is used in this analysis.

The utility factor for a PHEV is the portion of driving which will be performed on electricity on an aggregate basis. A vehicle like the Volt which is very electric intensive will have a high utility factor. For this analysis 0.7 was used (70% electric driving). This is lower than would be expected from the average daily mileage (as an example, 17000 miles per year divides into about 47 miles per day, about 18% above the 40 miles range of the Volt), but analysis of trip data has indicated that daily variation reduces the aggregate value. For example, recent work by General Motors indicates that a vehicle like the Volt will have a utility factor of 0.7 with nightly home charging, and a utility factor of 0.9 is possible with more frequent charging.⁶

⁶ Tate, E.D., Savagian, P. The CO₂ Benefits of Electrification; E-REVs, PHEVs, and Charging Scenarios. SAE 2009-01-1311 (2009).

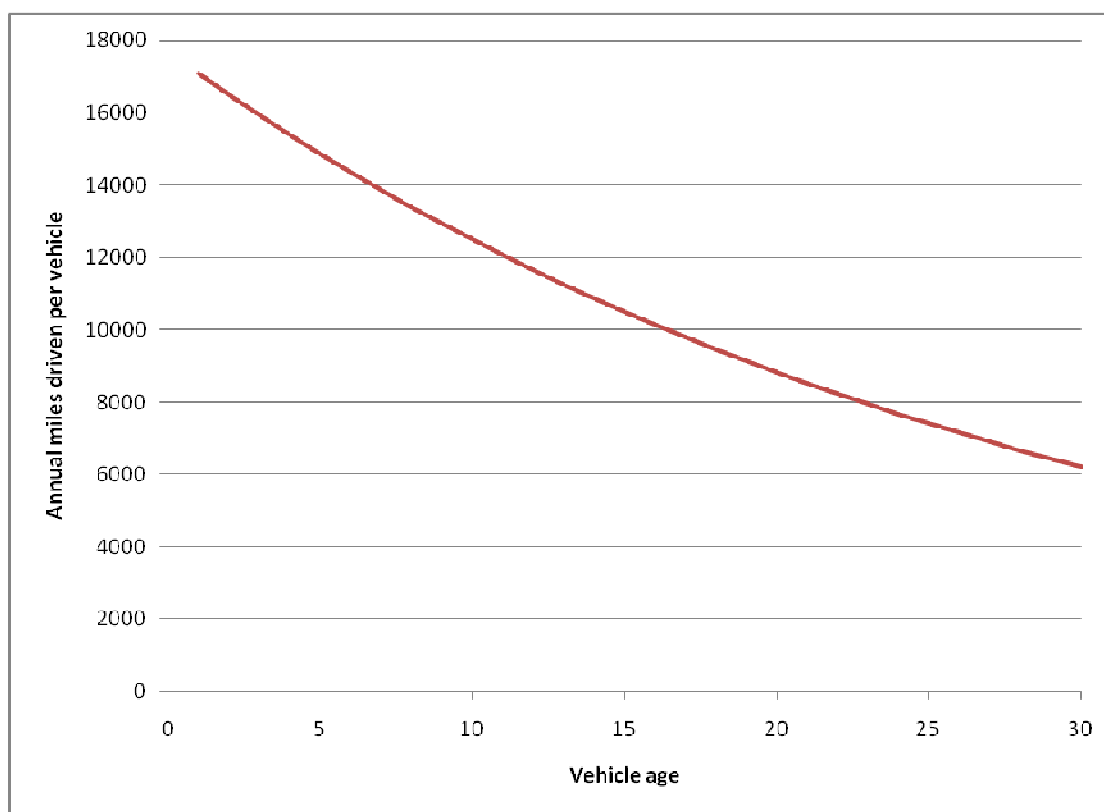


Figure 4: Annual vehicle miles traveled in California verses vehicle age

Incremental cost – Incremental cost is difficult to determine, and is also treated as an explicit variable. It is important to consider that costs of early generation technologies are often high, but decrease as subsequent generations of vehicles are introduced which incorporate increased knowledge. The reference Chevy Malibu Hybrid costs about \$25,000, and the cost of the initial Chevy Volt has been suggested to be about \$40,000 (General Motors has made no announcement concerning the price for the Volt), which suggests an incremental cost of about \$15,000. This analysis assumes a simple cost model in which costs decrease to \$7,500 in the second generation and \$4,500 in the third generation.

Neglected cost factors – There are some cost factors which have been neglected in this analysis due to a high degree of uncertainty.

Maintenance costs – Routine maintenance costs are expected to be lower for an electric-intensive vehicle like the Volt than for a conventional vehicle since lower utilization of the engine and brakes will increase service intervals. Additionally, a number of components will be replaced with solid-state or higher reliability components, such as the transmission, alternator, air conditioner, and power steering. These costs have a significant impact on lifecycle ownership costs for conventional vehicles. However,

given a lack of data and the potential for higher failure rates for first generation technologies these costs have been left out of this analysis.

Charging infrastructure – Charger costs are neglected in this analysis since it is uncertain where charging would occur and how much the infrastructure would cost. It is possible for most consumers to charge at home with minimal infrastructure cost, but this may not allow a sufficient charge rate for many consumers. It is assumed that additional infrastructure upgrades would be undertaken if they provided sufficient value to a particular consumer.

Secondary battery value – After the traction battery has been removed from the vehicle at the end of the vehicle life it may still have sufficient energy and power to be used in another application, such as a vehicle with less stringent battery requirements or a stationary application. This value is highly uncertain at this point and the production quantities of initial vehicles will likely be low enough that it would not be economically efficient to reprocess the batteries in this way, but this value may become significant in a mature market.

Different automaker strategies for pricing vehicles. Cost is not the same as price. The conversion of production cost into consumer price is arguably the most difficult step in a life cycle cost analysis. This is partly due to each automaker having a different way of doing this as part of their business plan.

Given these cost assumptions, Figure 13, Figure 14, and Figure 15 in Appendix C show the incremental cost minus the discounted savings for a PHEV verses the reference vehicle for gasoline costs of \$2.00 per gallon, \$3.00 per gallon, and \$4.00 per gallon respectively. Future savings are discounted to account for the fact that the consumer has the alternative of investing the money which they would use to pay upfront capital costs in a risk-free investment. The first year in which a consumer would have net positive savings is:

	Upfront cost		
	Generation 1	Generation 2	Generation 3
	\$15,000	\$7,500	\$4,500
Gasoline \$2.00/ gallon	*	*	10
Gasoline \$3.00/ gallon	*	10	5
Gasoline \$4.00/ gallon	*	6	3

Note that without discounting the first year in which a consumer would have net positive savings is:

	Upfront cost		
	Generation 1	Generation 2	Generation 3
	\$15,000	\$7,500	\$4,500
Gasoline \$2.00/gallon	*	13	8
Gasoline \$3.00/gallon	*	7	4
Gasoline \$4.00/gallon	11	5	3

Cells with an asterisk (*) do not become positive over a 15 year vehicle lifetime, about 200,000 miles.

The above analysis does not assume the presence of incentives. In the initial years of deployment, a purchaser of an electric-intensive PHEV like the Volt should receive a federal tax credit of about \$7,500, and later vehicles should receive a smaller, but significant, tax credit. This would likely make a Generation 1 vehicle equivalent to a Generation 2 vehicle, and would make a Generation 2 vehicle equivalent to a Generation 3 vehicle.

Other comments

1. Introduction

Page 9: “through large battery technology purchase orders” It’s not clear exactly what is meant here. Large purchase orders of vehicles are unlikely to change the cost situation since the number of vehicles will likely be supply limited in the near term, but purchases of automotive-grade batteries for use in stationary energy storage could potentially affect the market.

Page 11: “Automakers that have already deployed or announced ...” Additionally Hyundai and Volkswagen have announced the intention to build PHEVs or EVs.

Page 11: “Renault-Nissan” In the US, Renault-Nissan is referred to as “Nissan.”

Page 11: “or potentially in a flywheel” In general flywheel energy storage has not proven effective in passenger vehicles. In the near term braking energy captured by a PEV will be stored in a battery or potentially an ultracapacitor.

Page 12: “increased amount of electrical energy obtained from overnight charging” Although overnight charging would be beneficial for grid operators, it is not necessary to charge during the night to capture the benefits of electrification. The primary benefit

comes from the increased efficiency of electricity generation verses on-board combustion.

Page 13: “Moore’s law assumes every doubling” Looking at the referenced source, it is not clear that this “Moore’s law” is the same one often cited for computer processor development. The processor “Moore’s law” applies narrowly to certain semiconductor products, and is common result rather than a rigorous relationship. This cost model is not commonly used in making forward cost estimates for electric drive components or batteries.

Page 14, 18, and 31: In reference to the number of BEVs and PHEVs required by the ZEV mandate, EPRI recommends that the CPUC consult with CARB staff to get a better estimate of these figures. This program is quite complex and contains a number of factors which may increase or decrease the total.

2. Environmental Benefits and Costs of LDV Electrification

Page 16: “other criteria air pollutants” Criteria pollutants are actually more narrow than this; PM10, PM2.5, oxides of nitrogen (NOx), and Volatile Organic Compounds (VOCs) fit into this, but methane and hydrofluorocarbons do not due to low reactivity.

Page 16: “a conventional vehicle is about 37% efficient” This is high even for a peak efficiency; the operational efficiency is closer to 20%.

Page 17: EPRI recommends a review with CARB of the impact of transportation emissions on the state of California to consider a more complete “well to tank” emissions analysis.

Page 22: Lithium is characterized as limited relative to the amount which would be required for a fleet of PHEVs. Lithium is a limited resource, however, it is recyclable and the amounts which are expected to be used are small relative to the amount required for vehicles. Initial recycling process experiments indicate that 90% of lithium is recoverable during battery recycling.⁷ In an analysis which includes recycling, it was found that a transformative shift to advanced HEVs, PHEVs, and EVs, which included the creation of 465 million vehicles by 2050, required 0.4 – 1.8 million metric tonnes of lithium, depending on battery type, verses a total resource reserve of 4.1 million tonnes and a reserve base of 11.0 million tonnes.⁸ A separate analysis which focused on near-

⁷ Paulino, J.F., Busnardo, N.G., Afonso, J.C.. Recovery of valuable elements from spent Li-batteries. Journal of Hazardous Materials 150 (2008) 843-849.

⁸ Gaines, L. Lithium-Ion Battery Recycling Issues, 2009.

http://www1.eere.energy.gov/vehiclesandfuels/pdfs/merit_review_2009/propulsion_materials/pmp_05_gaines.pdf

term impacts also found that vehicle battery requirements were well within likely supplies until 2017, or 2030 if Bolivian supplies are brought online.⁹

Page 22: “Some stakeholders are concerned that toxicity levels associated with such waste streams may pollute soil and groundwater around landfills. Battery toxicity is found to be less problematic for lithium-ion and nickel metal hydride batteries ... than lead acid or nickel cadmium.” Toxicity of any compound is complicated, but it is incorrect to classify lithium-ion batteries as being similar to lead acid or nickel cadmium batteries. As summarized in one review: “lithium is not expected to bioaccumulate, and ... its human and environmental toxicity are low. Neither lithium intake from food and water nor from occupational exposure presents a toxicological hazard.”¹⁰ This is an area which should be studied in more detail, but it would be more correct to state that lithium ion batteries are generally considered to be non-toxic, but that further study of the specific chemistries used should be undertaken to ensure that previously unencountered effects do not occur.

Page 23: “The CARB rulemaking to implement AB1493 includes a Zero Emissions Vehicle (ZEV) automaker deployment mandate” The ZEV mandate predates AB1493, and was originally intended to reduce criteria air pollutants. Although it does have an impact on greenhouse gasses, it is a separate effort based on different metrics.

Page 24: In the discussion of the LCFS, the paper should also mention the full fuel cycle emissions for other fuels like petroleum in order to show that electricity is a low carbon fuel relative to other options. In the current version, it is difficult for those unfamiliar with the standard to determine how much of a reduction in emissions electricity would allow. For example, CARB in its LCFS analysis found electricity as a light duty transportation fuel to be about 64 percent less greenhouse gas intense than gasoline or diesel fuel. The CEC in the State Alt Fuels Plan did a similarly sophisticated analysis, and found results that are much lower than the worst case scenario portrayed on page 19 of the White Paper.

Page 26: There are additional environmental policy drivers in California and federally. The White Paper should be expanded to include the electric transportation sections of the IEPR, the Energy Action Plan 2, and the State Implementation Plan (for the state and federal Clean Air Acts). At the federal level a good resource on the existing 40 federal policies and programs is Chapter 7 in the March 2009 book “Plug-in Vehicles – What Role for Washington” David Sandalow, editor, published by the Brookings Institute.

⁹ Lache, Rod, et. al. Electric Cars: Plugged in; Batteries must be included. Deutsche Bank, 2008. Private correspondence with one of the authors also indicates that the estimate of lithium requirements per battery may be an overestimate of 70-170%.

¹⁰ Aral, H., Vecchio-Sadus, A. Toxicity of lithium to humans and the environment – A literature review. *Ecotoxicology and Environmental Safety* 70 (2008) 349-356.

3. Economic Benefits, Costs, and Barriers to Entry

Page 30: “The cost of the second device would be born by the customer, as it is located on the “customer side” of the meter.” This is not specifically correct. The second meter or sub-meter is not considered to be on the customer side of the meter; it is on the utility side of the meter. In the past, the CPUC has ruled that the cost of these second meters should be borne by the individual electric transportation customer. However, some people have argued that these second meters or sub meters (with TOU or other load management capability) should be treated like other load management devices, which provide benefits to all ratepayers, and therefore the costs of these second meters or sub meters should be borne by all ratepayers.

4. Other Barriers to PEV Commercialization

Page 44: “Fast charging is designed to make the consumer indifferent to allocating five minutes to fill up at the gasoline pump versus filling up at a 33 Kw or 400 amps for five minutes.” It would be good to define specifically what fast charging is in this context, since there are a number of different versions being discussed. 33 kW would not typically be considered fast charging; 250 kW is closer to a typical number.

5. Existing and Pending Policies/Programs Supporting PEV Commercialization

Page 56: “CNG vehicles are currently the only vehicle classified as “AT-PZEV” pursuant to the CARB ZEV program.” In addition to CNG vehicles, most hybrid vehicles are classified as AT-PZEVs. Hydrogen internal combustion engine vehicles and plug-in hybrids, when they become available, are eligible to be “Enhanced AT-PZEV” vehicles.

Page 68. On “Franchise Tax Board Options”, the issue of potentially imposing a highway tax or other taxes on electricity used as a transportation fuel has been considered by State policy makers several times. This issue was the subject of legislative hearings at the State Capitol in the mid-1990’s. The conclusion of those hearings was that the existing amount of electricity used for transportation purposes is too small to generate meaningful revenue, and too small to justify the administrative mechanisms necessary to collect the tax. Further, imposing as tax on this developing market would act as a disincentive to consumers, at a time when the State wants to encourage its use. And there is uncertainty as to just how big and how fast this market will develop. Should electricity become a significant transportation fuel in the future, these policy-makers concluded, then this issue of whether it should be subject to a highway tax or fuel tax should be revisited at that time.

Also, electricity is already taxed at both a state level and many local levels, so if electricity used for transportation is to be subject to a highway or fuel tax, then policy makers should also consider whether the existing taxes on this electricity should be removed for this purpose.

General

All references to 110V electricity and 220V electricity should be changed to 120V and 240V (or 240/208V) respectively. These are the standard voltages, although the actual delivered voltage can differ from this within a regulated range.

Appendix A: Trends and Examples of Water Requirements for Electricity

Table 2 shows the fresh water consumption for electric generation for California and the rest of the country.

Table 2: Specific fresh water consumption for electric generation by state

State	Thermoelectric Power Generation million kWh per year	Freshwater Consumption Gal/kWh
Idaho	0	0
Massachusetts	32,568	0
Rhode Island	266	0
Tennessee	70,693	0
Delaware	5,805	0.01
South Dakota	2,682	0.01
Maryland	41,381	0.03
Hawaii	6,102	0.04
California	72,800	0.05
New Jersey	22,606	0.07
Virginia	48,757	0.07
Connecticut	26,342	0.08
Iowa	31,227	0.12
New Hampshire	13,411	0.12
Alabama	81,708	0.14
Florida	142,726	0.14
Nebraska	22,798	0.19
North Carolina	89,467	0.23
South Carolina	71,076	0.26
Arkansas	35,825	0.29
Maine	4,406	0.29
Washington	12,740	0.29
Alaska	3,611	0.31
Missouri	60,922	0.31
Arizona	62,551	0.32
Vermont	4,215	0.35
North Dakota	25,193	0.36
Mississippi	25,001	0.39
Indiana	100,579	0.41
Minnesota	39,561	0.44
Texas	248,095	0.44
Wisconsin	42,818	0.49
Wyoming	36,975	0.49
Michigan	92,628	0.50
Colorado	29,312	0.51
Oklahoma	42,818	0.51
Pennsylvania	160,926	0.54
Nevada	18,104	0.56
Utah	30,269	0.57
Kansas	36,496	0.58
West Virginia	75,769	0.59
Georgia	88,797	0.60
New Mexico	27,875	0.63
Oregon	3,468	0.82
New York	72,896	0.85

Ohio	129,316	0.95
Montana	8,401	0.96
Illinois	140,811	1.05
Kentucky	67,627	1.10
Louisiana	51,918	1.56
D.C.	181	1.61
US Weighted Average		0.47 Gal/kWh

Table 3 shows how water withdrawal and consumption has changed from 1950-2000 (the USGS will provide values for 2005 later in 2009) in the US as thermoelectric generation has increased.

Table 3: Water Use for Thermoelectric Generation

Year	Thermoelectric Withdrawal				Thermoelectric Generation	%Saline	%Fresh	Average Specific Withdrawal Rate Gal/kWh	Average Specific Consumption Rate Gal/kWh
	Total	Saline	Fresh	Consumption					
	<i>Billion Gal/day</i>	<i>Billion Gal/day</i>	<i>Billion Gal/day</i>	<i>Billion Gal/day</i>	<i>Thousand kWh</i>				
1950	40	10	30		232,813,441	25%	75%	62.75	
1955	72	18	54		433,786,447	25%	75%	60.62	
1960	100	31	69	0.2	609,575,587	31%	69%	59.92	0.12
1965	130	43	87	0.4	861,132,522	33%	67%	55.14	0.17
1970	170	53	117	0.8	1,283,797,575	31%	69%	48.37	0.23
1975	200	69	131	1.9	1,617,410,777	35%	66%	45.16	0.43
1980	210	71	139	3.2	2,009,985,111	34%	66%	38.16	0.58
1985	187	59.6	127.4	6.2	2,187,292,320	32%	68%	31.23	1.04
1990	195	68.2	126.8	4	2,592,755,151	35%	65%	27.47	0.56
1995	192	60	132	3.7	2,860,161,143	31%	69%	24.52	0.47
2000	195	59.5	135.5	*	3,334,267,510	31%	69%	21.36	

* Year 2000 consumption data not available

The trend in water withdrawal can be seen clearly in Figure 5. Figure 6 shows how the marginal withdrawal rate, the additional water needed per additional kWh of electricity generated has varied over this timeframe (per five-year period). The changes have been dramatic and are attributable to a variety of factors, including (but not limited to) the penetration of closed-cycle cooling technologies, retirement of oil-fired power facilities, integration of highly efficient steam-generation technologies (nuclear and combined-cycle natural gas), and development of low-water technologies (spray enhanced cooling, dry cooling, or use of degraded water). From 1950 to 2000, the average specific withdrawal rate for thermoelectric generation has decreased three-fold, from approximately 63 gal/kWh to 21 gal/kWh.

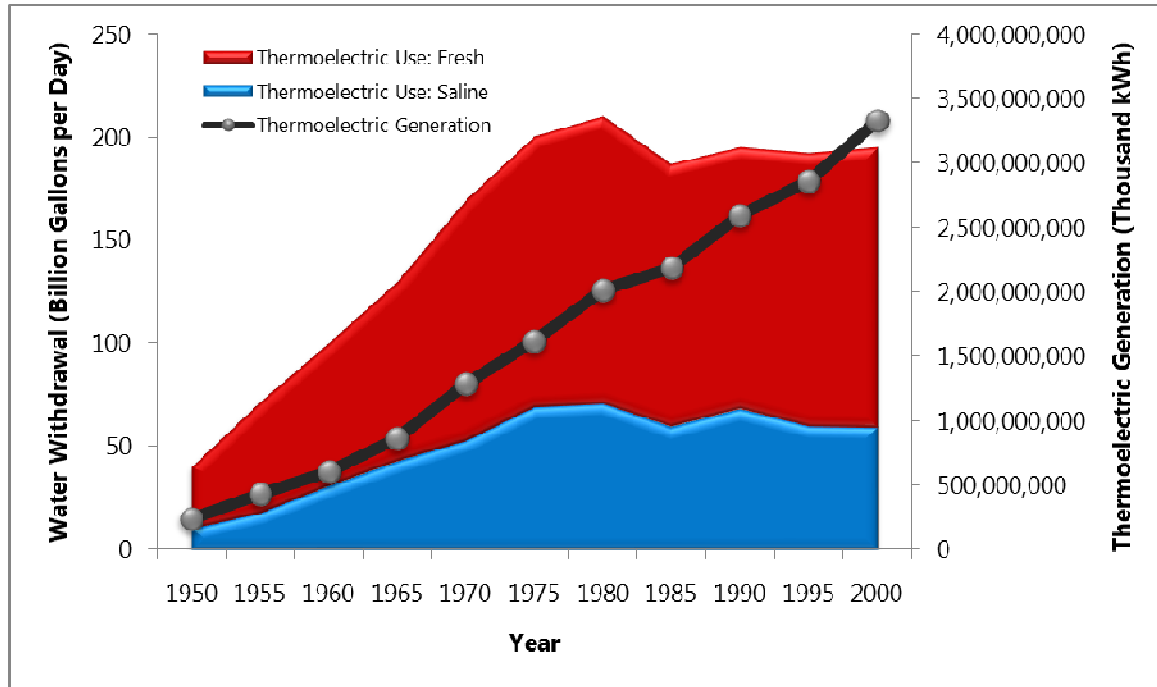


Figure 5: Water withdrawal for thermoelectric cooling

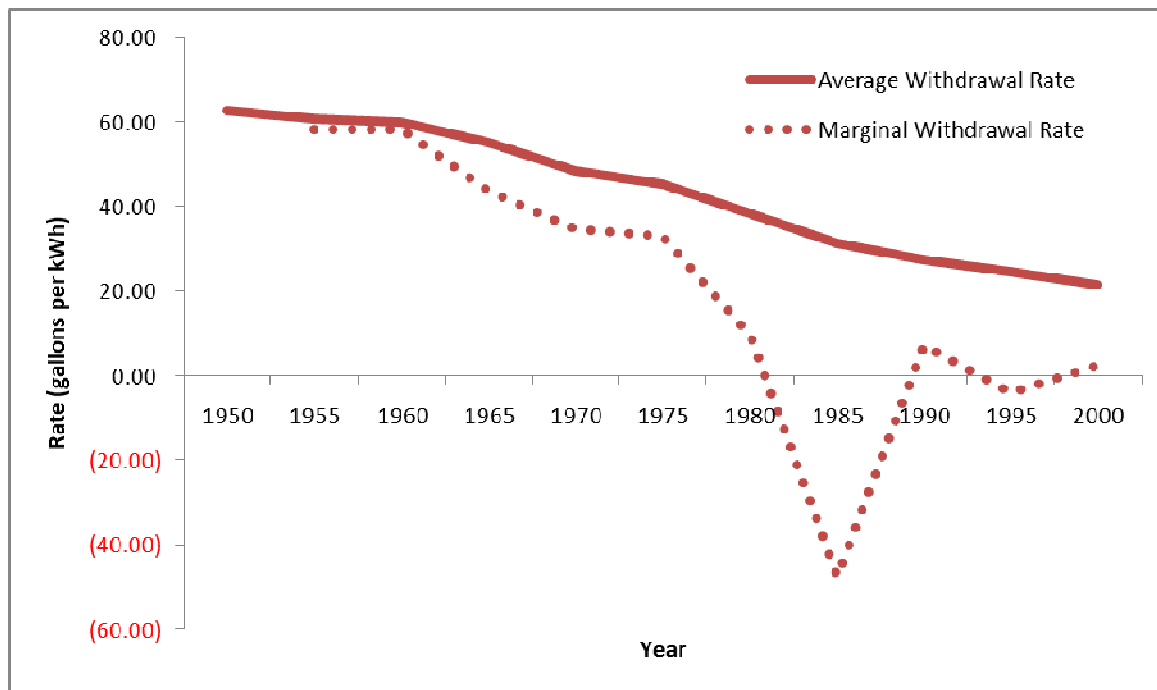


Figure 6: Specific average and marginal water withdrawal rates

From 1975 to 2000, the absolute withdrawal rate has remained relatively constant (197 billion gal/day \pm 4%), while thermoelectric generation has doubled in the same period. As noted in the figure, specific marginal withdrawal rates have been decreasing and even had to go to negative values (either by retirement or retrofitting) in order to satisfy

these trends. From 1990-2000, specific water withdrawal rates for the industry have been essentially hovering around the zero gal/kWh.

Water resources are evaluated not only on how much water they withdraw, but ultimately by the disposition of the water, i.e., how much water is consumed versus how much water is returned to the source. Figure 7 compares the share of **freshwater** withdrawals to the share of water consumption according to sector.

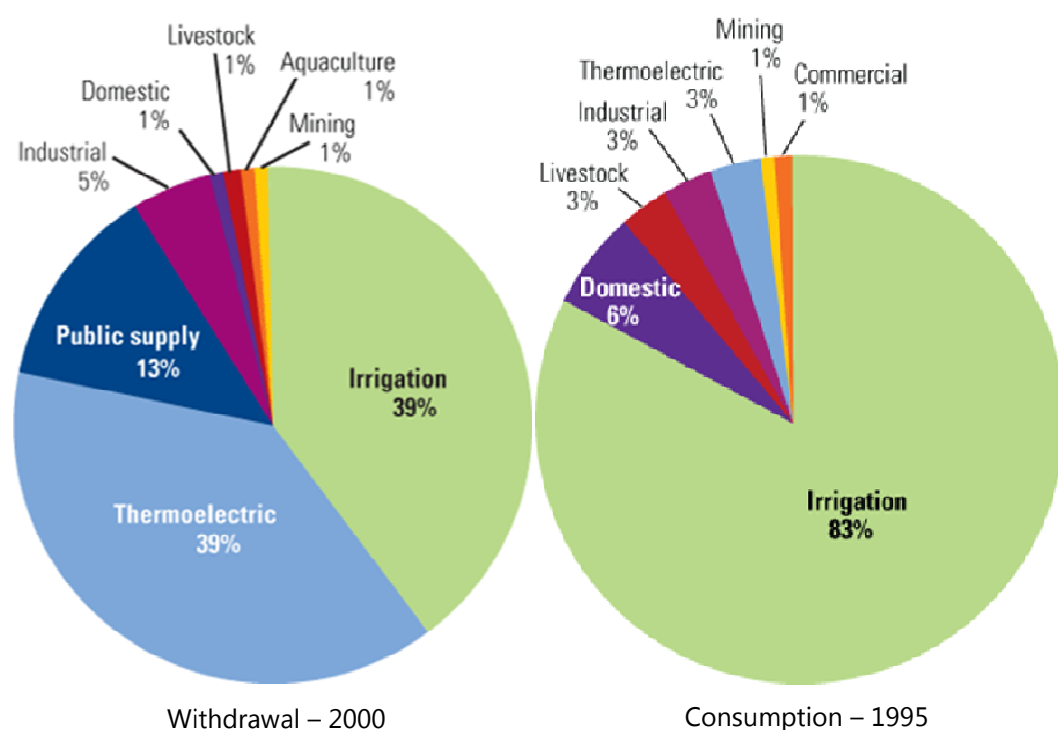


Figure 7: Share of Water Withdrawal and consumption in the United States according to use

Figure 7 depicts the national share of water withdrawals and consumption in the United States. However, the regional differences can be quite substantive. Figure 8 shows estimated freshwater flows in the U.S. Although the U.S. average freshwater withdrawal share for thermoelectric generation was 39%, Figure 9 and Figure 10 show that in California and New Mexico, the share was equal to 0.5% for that same year. It is instructive to note that although water withdrawals in New Mexico are very low, much of the water used in thermoelectric generation is consumed. In order to reduce water consumption rates, the Electric Power Research Institute is researching cooling methods that use degraded water (brackish waters or treated effluent) for thermoelectric cooling, thereby reducing the need to use freshwater in regions where water may be particularly scarce.

Estimated U.S. Freshwater Flow* in 1995: ~341,000 Mgal/day

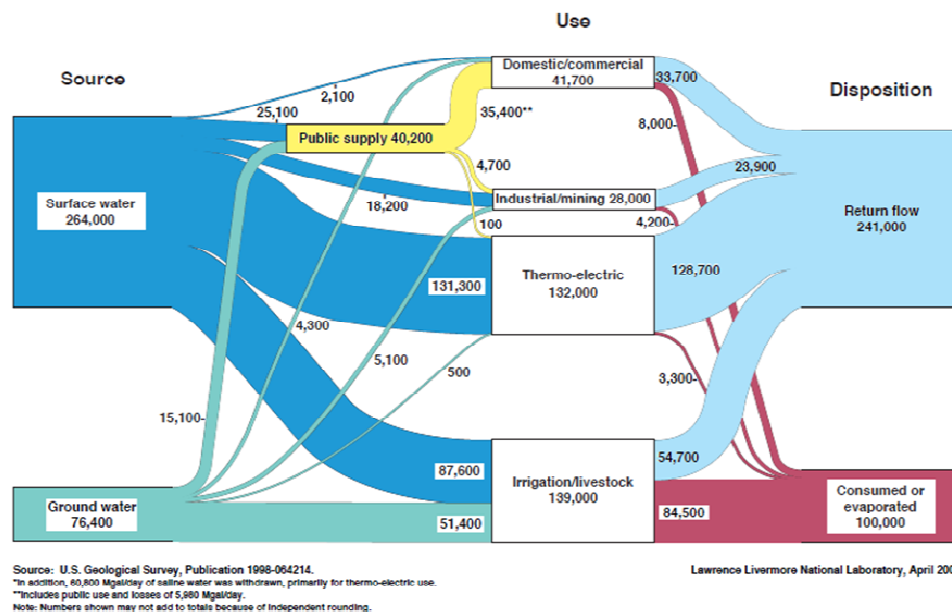


Figure 8: U.S. freshwater flow (source-use-deposition) in 1995

Estimated California Freshwater Flow in 1995: 36,000 Mgal/day

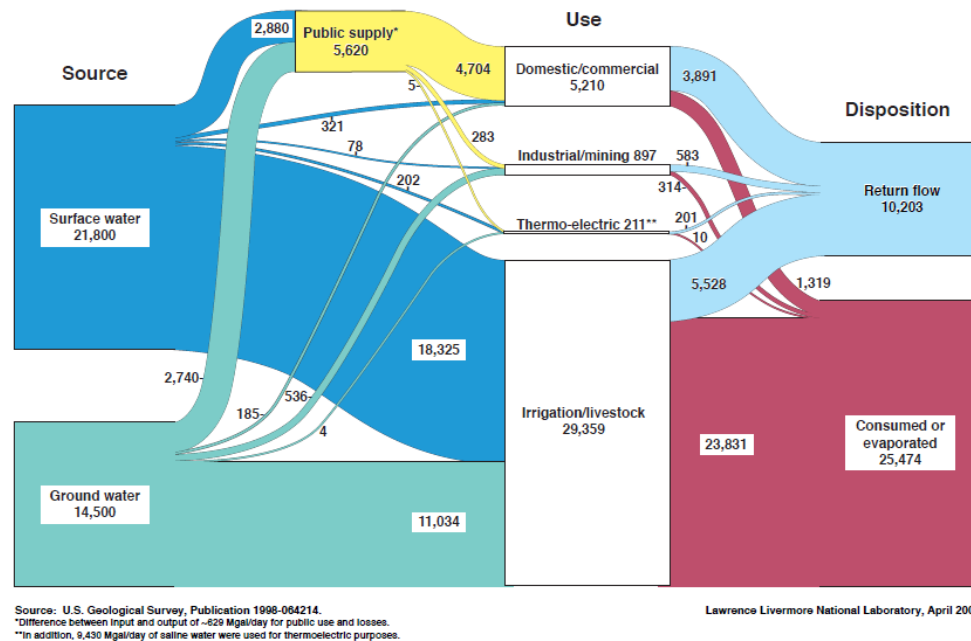


Figure 9: California freshwater flow (source-use-deposition) in 1995

Estimated New Mexico Freshwater Flow in 1995: ~3,500 Mgal/day

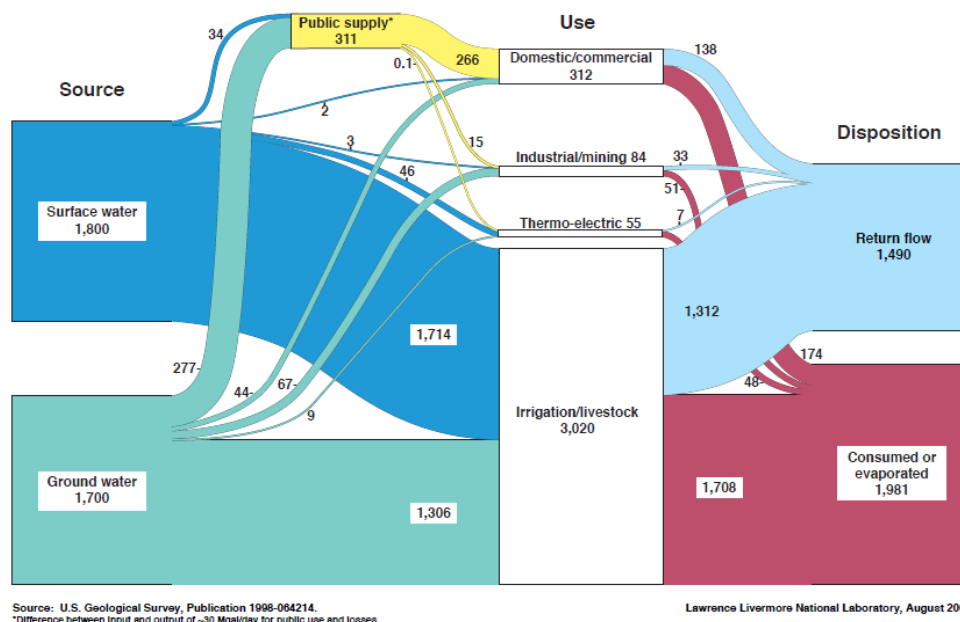


Figure 10: New Mexico freshwater flow (source-use-deposition) in 1995

Finally, when considering transportation fuels, the upstream water requirements are also important. Figure 11 represents the upstream water requirements (extraction, processing, storage and transport) related to different fuel sources and Figure 8 represents the potential cooling options for thermoelectric generation using these fuels.

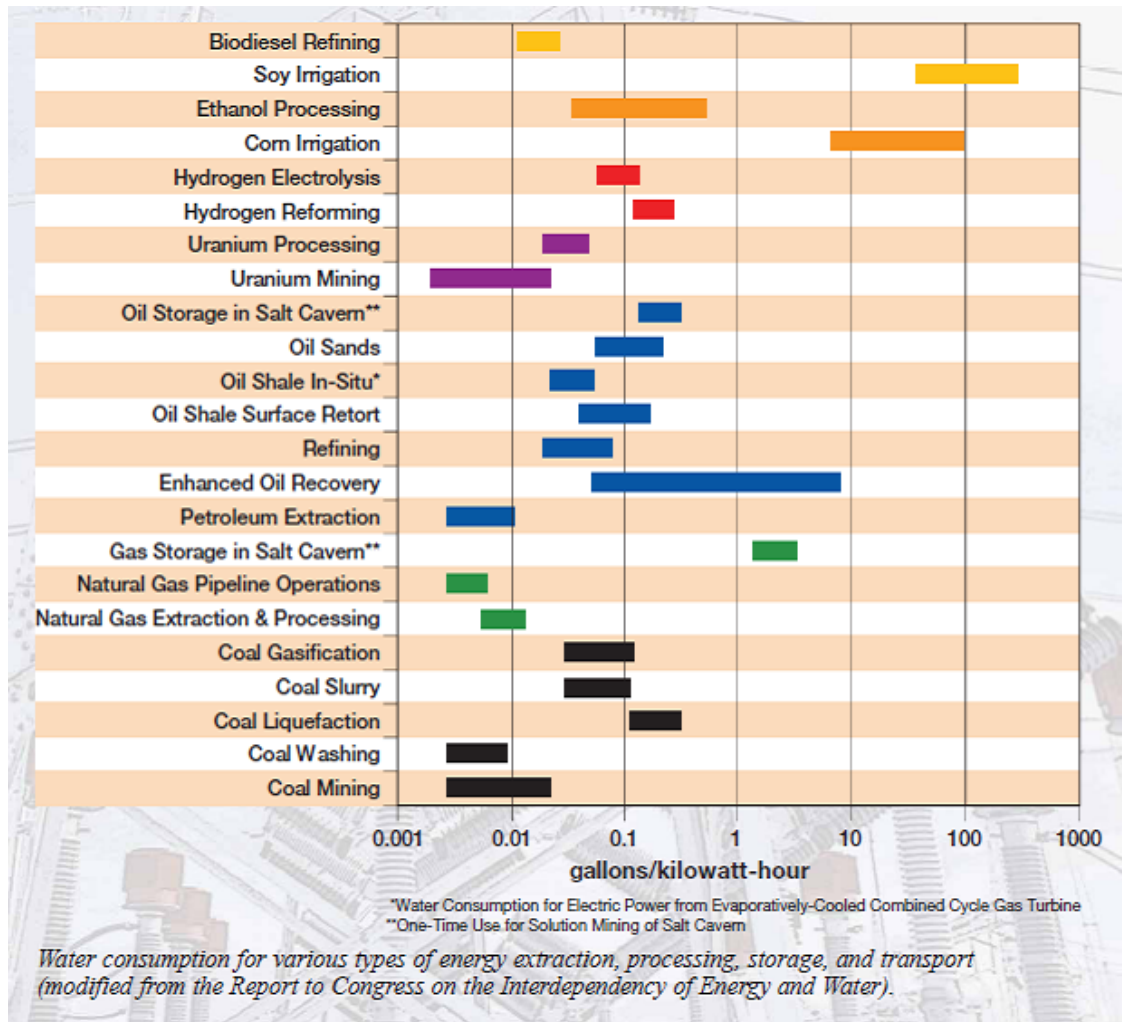


Figure 11: Upstream water consumption for various fuels and processes

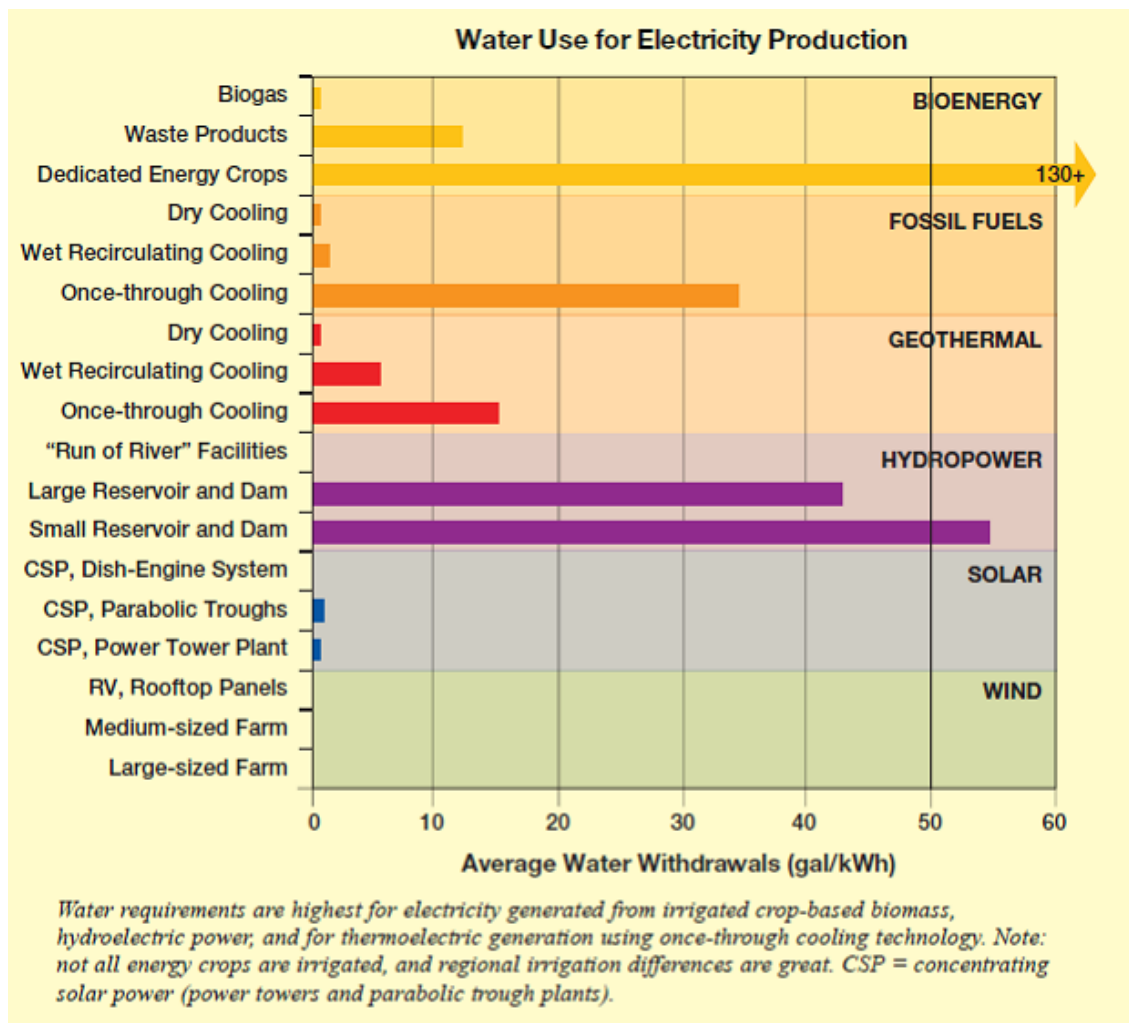


Figure 12: Life-cycle water use for electricity production from various energy sources (Nuclear, although not shown explicitly, has a similar intensity to the fossil fuel values shown.)

Appendix B: Additional Resources for Understanding Water Requirements of Electricity

These EPRI research reports on water-energy research have been released into the public domain. They can be accessed by visiting www.epri.com and entering the EPRI product number (10XXXXX) on the search function of the EPRI website.

Technology Research Opportunities for Efficient Water Treatment and Use, EPRI, 1016460, 2008

Use of Alternative Water Sources for Power Plant Cooling, EPRI, 1014935, 2008

Water Use for Electric Power Generation, EPRI, 1014026, 2008

Power Generation and Water Sustainability, EPRI, 1015444, 2007

Running Dry at the Power Plant, EPRI Journal, 1015362, 2007

An Energy/Water Sustainability Research Program for the Electric Power Industry, EPRI, 1015371, 2007

Water Resources for Thermoelectric Power Generation, EPRI, 1014487, 2006

Air-Cooled Condenser Design, Specification, and Operation Guidelines, EPRI, 1007688, 2005

Framework to Evaluate Water Demands and Availability for Electric Power Production within Watersheds across the US: Development and Applications, EPRI, 1010116, 2005

Comparison of Alternate Cooling Technologies for U.S. Power Plants: Economic, Environmental and other Tradeoffs, EPRI, 1005358, 2004

A Survey of Water Use and Sustainability in the U.S. with a Focus on Power Generation, EPRI, 1005474, 2003

Spray-Cooling Enhancement of Air-Cooled Condensers, EPRI, 1005360, 2003

Use of Degraded Water Sources as Cooling Water in Power Plants, EPRI, 1005359, 2003

Water & Sustainability (Volume 4): U.S. Electricity Consumption for Water Supply and Treatment, EPRI, 1006787, 2002

Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production – The Next Half Century, EPRI, 1006786, 2002

Water & Sustainability (Volume 2): An Assessment of Water Demand Supply and Quality in the U.S. – The Next Half Century, EPRI, 1006785, 2002

Water & Sustainability (Volume 1): Research Plan, EPRI, 1006784, 2002

Consumptive Water Use for U.S. Power Production, NREL/TP-550-33905, 2003; available at <http://www.nrel.gov/docs/fy04osti/33905.pdf>

Water Flow Charts 2000, LLNL/UCRL-TR-201457-00, 2004; available at <https://eed.llnl.gov/flow/pdf/UCRL-TR-201457-00.pdf>

Freshwater Flow Charts 1995, LLNL/UCRL-TR-201457, 2003; available at <https://eed.llnl.gov/flow/pdf/UCRL-TR-21457.pdf>

D. Larson, C. Lee, S. Tellinghuisen, A. Keller. California's Water-Energy Nexus: Water Use in Electricity Generation, Southwest Hydrology, 6(5), pp. 20, 21 and 30, 2007; available at http://www.swhydro.arizona.edu/archive/V6_N5/feature3.pdf

Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water,

U.S. Department of Energy, 2006; available at <http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf>

Estimated Use of Water in the United States in 1995, USGS Circular 1200, 1998; available at <http://pubs.usgs.gov/circ/2004/circ1268/pdf/circular1268.pdf>

Estimated Use of Water in the United States in 2000, USGS Circular 1268, 2004, revised 2005; available at <http://pubs.usgs.gov/circ/2004/circ1268/pdf/circular1268.pdf>

Appendix C: Cost Analysis Charts

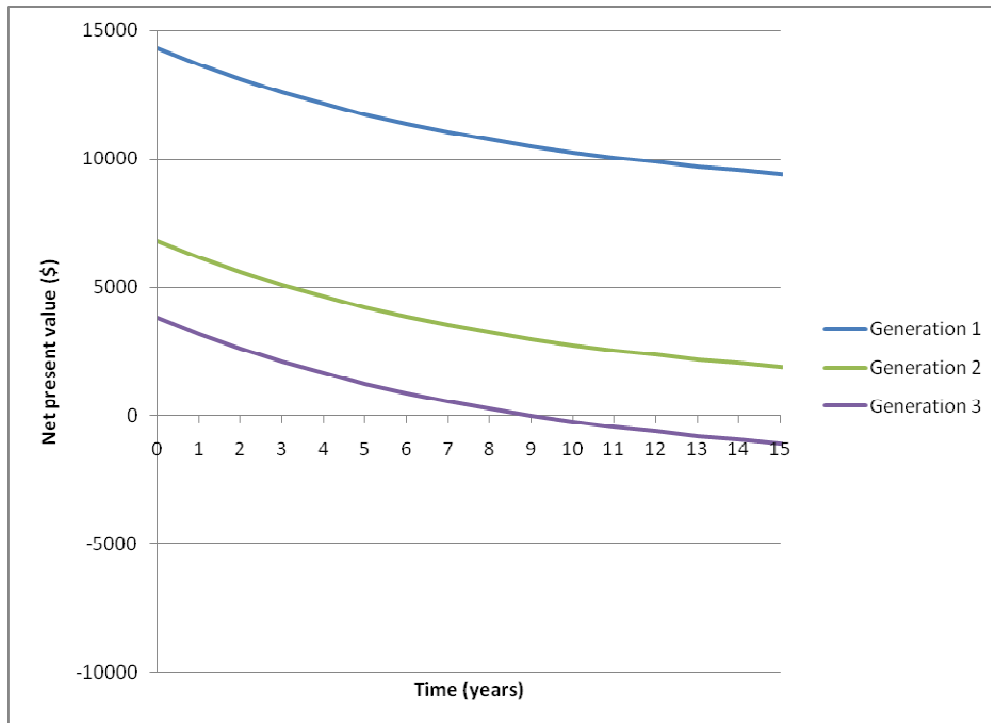


Figure 13: Incremental cost minus discounted savings for a gasoline cost of \$2.00 per gallon

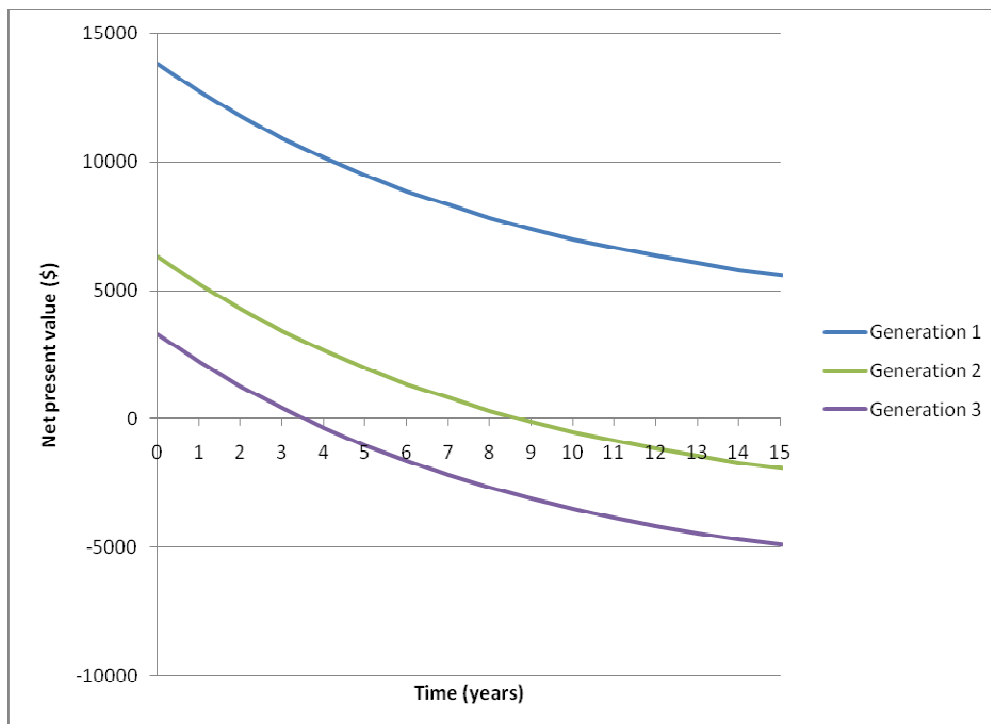


Figure 14: Incremental cost minus discounted savings for a gasoline cost of \$3.00 per gallon

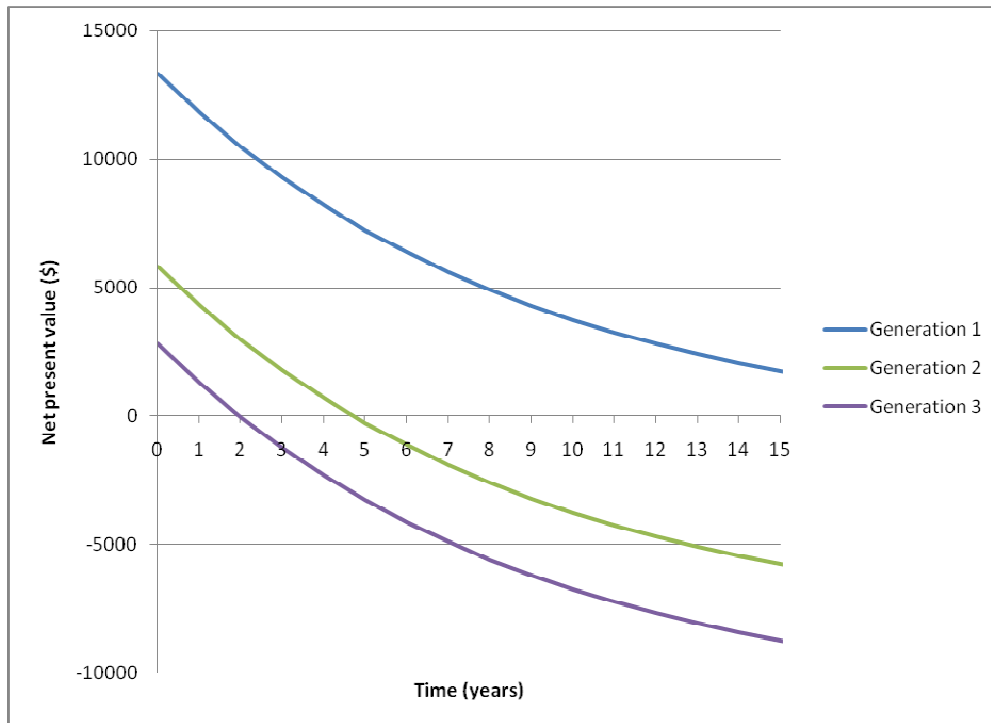


Figure 15: Incremental cost minus discounted savings for a gasoline cost of \$4.00 per gallon